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Attorneys for Southwest Energy Efficiency Project and Western Resource Advocates

BEFORE THE ARIZONA CORPORATION COMMISSION

JEFF HATCH-MILLER, CHARIMAN
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744	Docket No. E-01345A-05-0816 **NOTICE OF FILING DIRECT TESTIMONY AND EXHIBITS**

Western Resource Advocates, through its undersigned counsel, hereby provides notice that it has this day filed the written direct testimony and exhibits of David Berry in connection with the above-captioned matter.

Arizona Corporation Commission
DOCKETED

AUG 18 2006

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DATED this 18th day of August, 2006.

ARIZONA CENTER FOR LAW IN THE PUBLIC INTEREST

By______________________

Timothy M. Hogan
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Attorneys for Southwest Energy Efficiency and Western Resource Advocates

ORIGINAL and 13 COPIES of the foregoing filed this 18th day of August, 2006, with:

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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RATE OF RETURN THEREON, TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN, AND TO AMEND DECISION NO. 67744.	DOCKET NO. E-01345A-05-0816

Direct Testimony of

David Berry

Western Resource Advocates

August 18, 2006

Direct Testimony of David Berry
Docket No. E-01345A-05-0816

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List of Exhibits

Introduction

Q. Please state your name and business address.

A. My name is David Berry. My business address is P.O. Box 1064, Scottsdale, Arizona 85252-1064.

Q. By whom are you employed and in what capacity?

A. I am Senior Policy Advisor for Western Resource Advocates.

Q. Please describe Western Resource Advocates.

A. Founded in 1989, Western Resource Advocates (WRA) is a non-profit environmental law and policy organization dedicated to restoring and protecting the natural environment of the Interior American West. We have developed strategic programs in three areas: water, energy and lands. We meet our goals in collaboration with other environmental and community groups and by developing solutions that are appropriate to the environmental, economic and cultural framework of the region. Western Resource Advocates has been involved in Arizona utility regulatory issues for about 15 years.

Q. What are your professional qualifications for presenting testimony in this docket?

A. Exhibit DB-1 summarizes my experience and education.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of WRA and address the following topics:

- APS' proposed green power tariffs;
- Renewable energy as a hedge against high natural gas prices;
- Demand side management to reduce urban heat island effects;
- APS' proposed Environmental Improvement Charge (EIC);
- Development of a climate change policy, possibly in conjunction with the EIC.

Q. What are the major themes of your testimony?

A. APS faces high fuel and purchased power costs due to customer growth and higher fuel prices. Mr. Ewen (p. 6) indicates that the combined effect on APS' fuel expenses is $299 million.[1] The Commission should use this opportunity to build on actions taken in Decision No. 67744 to reduce APS' and ratepayers' exposure to high fuel costs by increasing the extent to which APS obtains low cost, stably priced energy from renewable resources and pursues cost effective energy efficiency programs. In addition, the Commission should use this Docket to encourage reduction of the environmental impact of power generation, including emissions of greenhouse gases.

Green Power Tariffs

Q. Please describe APS' proposed green power tariffs.

A. APS proposes two green power tariffs (Schedules GPS-1 and GPS-2, Attachments GAD-3 and GAD-4 to Mr. DeLizio's testimony). Under these tariffs, residential and non-residential customers have the option to buy green power from eligible resources such as solar, biomass, wind, geothermal, and small hydro resources. The existing solar partners tariff (which sells 15 kWh blocks of solar energy for a premium of $0.18 per kWh) would be frozen (Mr. Fox, p. 22).

APS' proposed green power premium is $0.03 per kWh and would be paid in addition to the otherwise applicable rate. The premium represents the net costs of non-distributed renewable energy above the cost of conventional generation (APS responses to data request WRA 1-1 and WRA 1-2) and was calculated by dividing the projected funding that would be provided by the proposed Renewable Energy Standard (RES) surcharge for non-distributed generation over the period 2006 through 2015 by the amount of non-distributed renewable energy required by the proposed RES from 2006 through 2015 (Mr. Fox, p. 21, APS response to data request WRA 1-2).

There are two green power options: a) customers can buy 25 kWh blocks of electricity per month for $0.75 per block, or b) customers can buy a set percentage of their monthly kWh consumption from green resources. For example, if a customer elected to buy 100% green power, a premium of $0.03 per kWh would be added to the monthly bill. If a customer elected to buy 10% green power, a premium of $0.003 per kWh would be added to all kWh consumed (10% of $0.03 per kWh). The percentages must be 100%, 50%, 30% or 10% of the electricity consumed.

Q. What is the relationship between RES and green power tariff resources as envisioned by APS?

A. In general, the resources used to meet the RES could also be used to serve green power customers. However, APS states (response to data request WRA 1-3) that it

[1] In Docket No. E-01345A-06-0009, APS' emergency rate case, Mr. Ewen indicates that APS' projected fuel costs have declined as natural gas prices have fallen from previous levels.

will record and report revenues from the green power tariff separately from the proposed RES tariff and any other tariffs. APS further indicates that funds collected from both the green power tariff and the RES tariff will be pooled to leverage purchasing power and to reduce fluctuations in demand for renewable energy resources as might occur with a resource dedicated solely to the green power tariff. APS also indicates that green power kilowatt hours will not be counted toward compliance with the RES and will be reported separately from RES resources.

Q. Are green power tariffs used in other jurisdictions?

A. Yes. The National Renewable Energy Laboratory estimates that in 2004, there were 324,000 residential and 8,100 non-residential customers of utility green power programs nationwide.[2] The median customer participation rate in utility green power programs is about 1%, but the top programs enroll around 4% or more of their customers.

Q. Does green power necessarily result in higher rates?

A. No. Public Service Company of Colorado's wind energy service rate adjustment effective November 1, 2005 was negative for several months because the cost of the wind energy was less than the cost of the electric commodity adjustment and the air quality improvement rider.[3] As a second example, Oklahoma Gas and Electric Company's green power premium is $0.001 per kWh but green power kWh are exempt from the fuel cost adjustment.[4] In June 2006, green power customers saved $16.60 for every 1000 kWh of green power purchased because the green power cost less than the fuel cost adjustment.

Q. Does WRA support the concept of green power tariffs for APS?

A. Yes. However, the terms and conditions of APS' proposed green power tariffs should be revised and clarified to make the tariffs successful and beneficial.

Q. Please describe the revisions and clarifications of the green power tariffs that WRA recommends.

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[2] Lori Bird and Blair Swezey, *Green Power Marketing in the United States: A Status Report (Eighth Edition)*, Golden, CO: National Renewable Energy Laboratory, NREL/TP-620-38994, 2005, Tables 2 and 3.

[3] Public Service Company of Colorado, Tariff Sheets Nos. 91 and 91A

[4] Oklahoma Gas and Electric Company, Schedule GPWR, Sheet Nos. 56.0 – 56.2.

A. There are several features of APS' proposed green power tariff that should be modified or clarified.

First, green power kWh should be exempt from the RES surcharge for the green power portion of consumption as green power customers will have already made an active commitment to renewable energy.

Green power kWh should also be excluded from the EIC because the green power does not contribute to the emissions that are to be reduced via the Environmental Improvement Charge. Green power kWh are excluded from the Environmental Improvement Charge according to the proposed Schedule EIC. However, Mr. DeLizio's testimony indicates that green power customers would pay the EIC as part of their standard rate which they must pay in addition to the green power premium (p. 4, starting at line 19).

Second, the determination of the green power "premium" needs to be revised as explained below. As proposed by APS, a fixed $0.03 per kWh premium would apply whether conventional fossil fuel costs are high or low, even though renewable energy resources might cost less than high priced natural gas resources, for example.

Third, the green power premium should be based upon costs of specific renewable energy projects (not projected RES funding as proposed by APS) and should be reviewed and approved by the Commission as the mix of renewable energy projects changes. As explained further below, APS should propose resetting the green power cost component as it acquires new resources to serve additional green customer load.[5]

Fourth, the green power tariff should not be available until APS has adequate renewable energy to serve green power customers. However, the start date for green power service should be no later than one year after the effective date of the Commission's order in this rate case.

Fifth, the minimum block size for customers desiring green power should be 100 kWh per month to meet Green-e default standards. The proposed 25 kWh block size is too small. APS' percentage proposal is satisfactory. Further, APS should seek Green-e certification for its green power product so that green power customers can be sure their purchases will be independently audited to verify that they were not used for RES compliance.[6]

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[5] APS indicated that it may need to revise the green power premium if RES funds do not match projected funds (response to data request WRA 1-2.)

[6] Center for Resource Solutions, *Green-e Accreditation of Utility Green Pricing Programs, National Default Criteria*, December 15, 2004 (Version I). APS has not decided whether it will seek Green-e certification (response to WRA 1-6).

Sixth, APS should submit public annual reports to the Commission detailing renewable energy acquired for the green power program by technology (e.g., wind, landfill gas, geothermal, etc.), customer enrollment by class (residential, commercial, industrial, other), green power kWh sales, green power revenues, and green power costs. These reports could be submitted as part of APS' RES reports.

Q. What process should be used to set the green power premium?

A. I recommend that APS select a set of low cost, stably priced renewable energy resources to serve green power customers and, within six months of the effective date of the Commission's decision in this case, propose a green power premium for the Commission's consideration reflecting the costs of the renewable energy resources and APS' avoided costs as described below. APS should seek renewable energy resources with fixed or stable prices that do not vary with the price of natural gas or spot market electricity prices. The resources can be a subset of those used to meet RES requirements. For marketing purposes it seems desirable that APS select lower cost renewable resources from its portfolio of non-distributed resources used to meet RES requirements.

Q. How should the green power premium be calculated?

A. The green power premium would be added to the otherwise applicable rate, excluding the RES surcharge and the EIC, as indicated above. The premium should be determined as follows: Premium = G – B – P – A, where:

G = the (total) cost per kWh of the green power,
B = the base power supply cost
P = the power supply adjustor, and
A = allowance for capacity credits associated with the green power.[7]

For example, if the green power cost, G, is $0.042 per kWh, B = $0.031904 per kWh (APS' proposed base fuel recovery rate per Mr. Ewen, p. 6, although APS may modify its proposed rate), P = $0.00, and A = $0.005 per kWh, the green power premium would be $0.005096 per kWh. The values for G, P, and A are illustrative.

Q. How can customers be informed of the green power premium in a way to minimize confusion?

A. The premium could be presented relative to standard rates with no power supply adjustor (P = $0.00) since the effect of the adjustor is arithmetically cancelled out as

[7] The renewable resources would, in general, have some capacity value which would displace conventional capacity needs.

explained below. Using the example from above, the green power premium would be \$0.005096 per kWh added to base rates excluding the power supply adjustor so that green power customers are exempt from the power supply adjustor.

Q. Why should green power customers be exempt from the power supply adjustor?

A. APS' (variable) power supply costs are the base power supply cost plus the power supply adjustor (which can be positive or negative). Because green power consumption avoids conventional power supply, the conventional power supply costs should not be included in the rates paid by green power customers. Mathematically, rate changes due to the power supply adjustor are subtracted from the standard rate (which includes the power supply adjustor) when applying the green power premium and hence the power supply adjustment cancels out. To illustrate, consider two hypothetical cases using the formula presented above:

case a. **High fuel prices**. Suppose the otherwise applicable rate is \$0.07 per kWh, which includes the base power supply rate of \$0.031904 per kWh. In addition, assume the power supply adjustor is +\$0.01 per kWh. The total rate paid by a regular customer is therefore \$0.08 per kWh (\$0.07 + \$0.01). Assume the green power costs \$0.042 per kWh and the capacity credit allowance is \$0.005 per kWh. The green power customer pays an effective premium of -\$0.004904 per kWh using the formula presented above (premium = \$0.042 - \$0.031904 - \$0.01 - \$0.005). The combined cost to the green power customer is the otherwise applicable rate including the power supply adjustor plus the green power premium for a total of \$0.075096 per kWh (\$0.07 + \$0.01 - \$0.004904). Note that during a period of high conventional fuel costs, the green power customer pays a lower rate than regular customers.

case b. **Lower fuel prices**. Suppose the otherwise applicable rate is \$0.07 per kWh, including the base power supply rate of \$0.031904 per kWh. In addition, assume the power supply adjustor is -\$0.01 per kWh. The total rate paid by a regular customer is therefore \$0.06 per kWh (\$0.07 - \$0.01). Assume the green power costs \$0.042 per kWh and the capacity credit allowance is \$0.005 per kWh. The green power customer pays an effective premium of +\$0.015096 per kWh using the formula presented above (premium = \$0.042 - \$0.031904 - [-\$0.01] - \$0.005). The combined cost to the green power customer is the otherwise applicable rate including the power supply adjustor plus the green power premium for a total of \$0.075096 per kWh (\$.07 - \$0.01 + \$0.015096), the same amount as case a, above. That is, the green power customer pays a constant rate, unaffected by the power supply adjustor. Note that during a period of low conventional fuel costs, the green power customers pays a higher rate than regular customers.

Q. What should happen as APS' renewable energy resources designated for the green power program become fully subscribed?

A. As the set of renewable resources approaches full subscription, APS should designate an additional set of renewable resources and, if necessary, propose a new premium to the Commission reflecting the cost of the new mix of resources. Customers desiring to subscribe when existing renewable resources are fully subscribed should be put on a waiting list until the additional resources become available.

Q. What should happen if APS acquires too much renewable energy compared to its green power sales?

A. Excess renewable energy could be used to meet APS' RES requirements, assuming that the renewable energy meets RES requirements, or APS could use the excess energy as part of its purchased power portfolio for serving all of its retail customers.

Using Renewable Energy as a Hedge against High Natural Gas Prices

Q. Does APS use large quantities of natural gas to generate electricity?

A. Yes. APS forecasts that it will consume about 65 million MMBtu of natural gas in 2006 in its own power plants for its own load (Ewen workpaper PME_WP3, p. 6). In addition, APS will purchase power generated from natural gas.

Q. What prices have been paid by the electric power sector for natural gas?

A. Exhibit DB-2 (upper panel) shows natural gas prices paid by the US electric power sector from 1992 through 2005 in constant year 2005 dollars per MMBtu and a forecast price for 2006.[8] Note the significant increase in prices in the last few years. In 2005, the electric power sector paid over $8.00 per MMBtu.

Q. How does APS utilize its gas-fired generating units?

A. APS has gas-fired combustion turbines, steam plants, and combined cycle plants. In general, natural gas-fired generation is APS' marginal resource. That is, it is APS' highest cost conventional generation and gas-fired plants would, in general, be the first to be backed off if alternative resources are available. Mr. Ewen's workpapers

[8] Data from Energy Information Administration, *Short Term Energy Outlook*, December 2005 through July 2006, Table A4. Forecast price is from the *Short Term Energy Outlook*, August 2006. Prices were translated to constant dollars using the gross domestic product implicit price deflator published by the Bureau of Economic Analysis.

(PME_WP3, p. 3) and APS' response to Utilitech's data request UTI-15-354 c and d suggest that APS uses natural gas generation in most hours of the year. The Red Hawk and West Phoenix combined cycle units are the largest users of natural gas.

Q. What can be accomplished by hedging against high natural gas costs?

A. A hedge would consist of actions intended to reduce a utility's and its ratepayers' exposure to uncertain high fossil fuel costs. Utilities can and do use financial hedges such as forward purchases, futures, and options in such situations. A utility can also reduce its need to obtain gas-fired generation by substituting energy efficiency or renewable resources for gas-fired generation, thereby reducing its exposure to high gas costs.

Q. Should APS hedge against the high cost of natural gas with renewable resources?

A. Yes. APS faces a long term exposure to high fossil fuel prices and should pursue a long term risk management strategy that goes beyond what it can accomplish through financial hedging of gas prices. Low cost, stably priced renewable resources would reduce APS' exposure to high gas prices by displacing gas-fired generation and would cost less than natural gas-fired resources when gas prices are high.

Q. What prices are utilities paying for renewable energy?

A. Exhibit DB-3 shows prices reported publicly for large scale wind projects in the west in 2005.[9] Wind energy produced at good sites sold for less than about $0.035 per kWh in 2005. Exhibit DB-3 also shows prices for <u>new</u> wind energy projects starting generation from late 2005 through 2007.[10] Prices for these new wind projects are higher than prices for older projects in part because of shortages of equipment and higher costs for construction materials. The equipment shortages may be temporary if demand for wind turbines grows more slowly in the future, manufacturing capacity increases, or competition among developers becomes more intense. In such cases,

[9] Prices from utilities' 2005 FERC Form 1 and Testimony of Gary Swarts, Before the Public Utilities Commission of Colorado, In the Matter of the Application of Public Service Company of Colorado for Approval of Lamar Wind Energy Supply Agreement and for the Rate Mechanism to Recover the Costs of the Agreement, August 21, 2002, p. 7.

[10] Sources: Los Angeles Department of Water and Power purchase from the Pleasant Valley Wind Energy Center in Wyoming (reported by Reuters, June 6, 2006), Nebraska Public Power District purchase from the Ainsworth Wind Energy Facility (reported by the Nebraska Energy Office, March 2006), Austin Energy purchase from Res American Developments (reported in the Austin American-Statesman, April 6, 2006) assuming a capacity factor of 35%, and contract between Spanish Fork Wind Park 2 LLC and PacifiCorp, dated June 20, 2006 (Utah Public Service Commission Docket No. 06-035-76, Exhibit A).

prices for new projects might fall. The Exhibit also shows prices for several Salton Sea area geothermal contracts with deliveries starting in 2005 to 2007.[11]

Q. How do renewable energy costs compare with APS' cost of generating electricity with natural gas?

A. APS' projected fuel cost of generating electricity from APS' natural gas units is shown in Exhibit DB-3. Wind and geothermal energy projects are generating electricity at prices competitive with APS' projected fuel costs for generating electricity with natural gas.

Q. What would the price of natural gas have to be for renewable energy to be less costly?

A. Exhibit DB-2 (lower panel) shows the midpoints of ranges of break-even prices of natural gas for wind resources at 2005 prices, for new wind resources at the higher 2006 prices, and for geothermal resources at recent prices for Salton Sea area projects. The break-even prices shown in the Exhibit are the natural gas prices at which the cost of renewable energy equals the avoided energy and capacity costs of natural gas-fired generation. The cost of wind energy includes wind integration costs.

The break-even prices are plotted against the percentage of conventional generation which is displaced by renewable energy that would have otherwise been generated using natural gas. The chart assumes that the remaining percentage of displaced generation would have been generated with coal.[12]

[11] Geothermal contract prices from: Ormat Technologies press releases dated December 13, 2005 and June 14, 2006, MidAmerican Energy Holdings press release dated June 6, 2006. Prices shown are for the first year of the contracts. Prices escalate at a fixed rate (1% or 1.5% per year) after the first year.

[12] Wind and geothermal energy contract costs are those shown in Exhibit DB-3, excluding the Nebraska contract whose price is more reflective of 2005 conditions. The Exhibit excludes the contracts negotiated by APS in 2005 to acquire 145 MW of renewable resources. Incremental transmission revenue requirements in excess of transmission that would otherwise have been needed for new conventional generation capacity are assumed to equal APS' OATT charges for point to point service. Wind energy costs also include costs of wind integration, that is, the utility's costs of maintaining a reliable system when intermittent wind resources are fed into the grid. Wind integration costs were taken from J. Smith, E. DeMeo, B. Parsons, and M. Milligan, "Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date." Golden, CO: National Renewable Energy Laboratory NREL/CP-500-35946, 2004.

The average heat rate of the gas-fired power plants displaced by renewable resources is assumed to be 8,480 Btu/kWh and the average heat rate of the displaced coal generation is assumed to be 10,838 Btu/kWh. The cost of coal is assumed to be $1.62 per MMBtu at the displaced coal plants. Variable O&M costs for the displaced gas generation was assumed to be $1.93 per MWh and for the displaced coal generation was assumed to be $4.28 per MWh, based on Energy Information Administration cost estimates contained in its *Annual Energy Outlook 2005*.

When the price of natural gas paid by the electric power sector is above the break-even price, renewable energy costs less. In recent years, gas prices have been sufficiently high that many wind and some geothermal energy resources are cheaper alternatives, especially as the percentage of time that gas-fired generation is displaced by renewable energy increases.

Future natural gas prices are uncertain, so it is appropriate to regard renewable energy resources as hedges against high gas prices in the future. The hedge value of renewable resources is enhanced when utilities purchase renewable energy at a fixed or stable price that is not tied to the price of natural gas. Wind, geothermal, and biomass contracts often feature fixed or stable prices.

Q. How can the Commission ensure that APS pursues a policy to reduce its exposure to high natural gas prices by increasing its use of renewable energy?

A. I recommend that APS be directed to obtain at least 1,300 GWH per year of stably priced renewable energy under long term contracts (at least 15 years) starting within the period 2008 to 2010.[13] <u>This 1,300 GWH per year is in addition to the renewable energy required by Decision No. 67744</u>. (Decision No. 67744 required APS to seek at least 100 MW of renewable energy generating capacity in 2005 and to seek to acquire at least 10% of its annual incremental peak capacity needs from renewable resources).

The 1,300 GWH is proposed because it is feasible and, when combined with the previous commitment, provides a significant hedge against high gas prices. With regard to feasibility, the renewable energy industry is active in the Southwest. For example, the industry has added about 400 MW of wind generation capacity in New Mexico between 2003 and 2005 (generating about 1200 GWH per year), has about 520 MW of geothermal production capacity in southern California (generating

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For wind generation, the capacity factor is assumed to be 35%. For geothermal generation, the capacity factor is assumed to be 90%.

The conventional generating capacity that can be avoided by deploying renewable energy resources is assumed to consist of gas-fired combustion turbines, the conventional resource with the lowest capital cost per kW of generating capacity. The capacity value of wind generation is assumed to be 25% of the nameplate capacity of the wind generators. The capacity value of geothermal energy is assumed to be 100% of the nameplate net capacity of the geothermal plant. The capital cost of a new combustion turbine is assumed to be $421 per kW (the purchase price of Sundance) and the capital recovery factor is assumed to be 15%.

[13] The 1300 GWH represents generation delivered to APS' transmission system before additional losses are incurred. If all the proposed renewable energy came from wind resources, approximately 425 MW of wind generation capacity would be needed. If all the renewable energy came from geothermal resources, approximately 165 MW of net geothermal generation capacity would be needed.

roughly 3900 GWH per year) with a potential for up to about 2000 more MW of capacity, and is developing a 35 MW biomass project in New Mexico.[14] In addition, the proposed level of renewable energy is large enough to result in significant displacement of gas generation and hence to result in a useful hedge against high gas costs as discussed further below.

I am proposing a three year "window" for starting the acquisition of the low cost, stably priced renewable energy to allow APS adequate time to obtain needed transmission capacity, to take advantage of market conditions such as the availability of production tax credits, and to work around shortages of equipment and materials.

I also recommend that APS file for Commission review, within 4 months of the date of the Decision in this Docket, a plan for acquiring the renewable energy. Prior to filing the plan, APS should consult, in a collaborative manner, with interested parties to this case to obtain input on development of the plan. Additionally, I recommend that APS file reports with the Commission by March 1, 2009, March 1, 2010, and March 1, 2011 describing its progress in meeting these goals and proposing actions to make up any deficiencies in meeting the goals, including acquisition of needed transmission capacity.

Q. Does APS have any experience acquiring low cost renewable resources as a hedge against high gas prices?

A. Yes. As a result of Decision No. 67744, APS arranged to acquire 145 MW of wind, geothermal, and biomass resources (Decision No. 68296). APS also agreed to add additional renewable energy so that the nameplate capacity of the renewable energy equals 10% of APS' increase in capacity needs, but these additional resources have not yet been acquired for years beyond 2008.

Q. Has APS sought other conventional resources for next three to eight years?

A. Yes. On January 24, 2006, APS issued a request for proposals for unit-specific base load generating capacity of 100 MW to 500 MW per unit for deliveries beginning as early as 2009 but starting no later than 2014.

Q. Suppose APS conducts a request for proposals for renewable energy but believes that it cannot use the resulting bids to reasonably hedge against high natural gas prices

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[14] Data sources: American Wind Energy Association, New Mexico Wind Energy Development, Geothermal Energy Association, www.geo-energy.org/information/plantsNow/ca/caAll.asp, California Energy Commission, "California Geothermal Resources," April 2005, CEC-500-2005-070, pp. 5-8, and Santa Fe *New Mexican*, July 31, 2006.

because of transmission constraints, low natural gas prices, or other conditions. What should APS do?

A. I recommend that APS include in its March 1 reports, described above, a detailed description of the problems encountered and recommended solutions. The Commission should then review APS' report and set a course of action for APS.

Q. Please compare your recommendation in this case with APS' commitments arising out of the previous settlement agreement (Decision No. 67744).

A. Exhibit DB-4 shows the relative amounts of renewable energy from the initial acquisition under Decision No. 67744, the additional amounts APS is supposed to seek under Decision No. 67744,[15] and WRA's recommended resources in this docket. From 2010 through 2016, APS would obtain between 6% and 7% of its energy from low cost, stably priced renewable energy resources as a result of this recommendation and the requirements of Decision No. 67744. During this same time period, renewable energy generating capacity would be between 6% and 7% of APS' own-load peak demand assuming the capacity factor for the mix of renewable energy resources is 50% and using APS' own-load peak demand forecast provided in response to Staff data request EAA 4-16.

Q. How much of APS' natural gas generation would be displaced by energy from renewable resources under your proposal and Decision No. 67744?

A. APS expects that about 26% of its own-load generation in 2006 would come from gas-fired power plants (Ewen workpaper PME_WP3, p. 3). Renewable energy would constitute less than 7% of APS' retail sales over the next several years (Exhibit DB-4). Therefore, the renewable energy would displace roughly a quarter of the gas generation that APS would otherwise produce.

Q. Isn't the Renewable Energy Standard sufficient for APS to hedge against high fossil fuel prices with renewable resources?

A. No, not for APS. The RES has not yet been adopted by the Commission. The pending RES renewable energy requirements are not maximums or caps on the amount of renewable energy a utility can acquire. My proposal accelerates the RES schedule because APS needs to hedge against high gas prices as quickly as possible. In 2010, APS would obtain about 6.4% of its energy from non-distributed renewable energy resources under my proposal plus commitments made in Decision No. 67744 (Exhibit DB-4). In contrast, APS would need to obtain only 2% of its energy from

[15] Exhibit DB-4 assumes that APS adds 27 MW of renewable energy generating capacity with an average 50% capacity factor each year.

non-distributed renewable energy resources under the RES in 2010. To the extent that renewable energy resources obtained as a gas price hedge are eligible for the RES, I recommend that they be counted toward meeting APS' RES obligations. APS could bank renewable energy in excess of the RES for use in later years in meeting the RES.

Q. How could APS recover the costs of the renewable energy?

A. I recommend that APS recover the costs through its power supply adjustor. However, to the extent that APS uses any of the renewable energy to meet its RES requirements, APS could recover costs via the RES cost recovery tariff approved by the Commission, consistent with APS' approved RES implementation plan.

Q. What are the effects of introducing large amounts of intermittent resources like wind on system reliability?

A. If my proposal is adopted, about 7% of APS' energy and about 7% of APS' peak load would come from renewable resources, but not all of that 7% would be from intermittent renewable resources. Thus, the amount of intermittent renewable energy introduced into APS' system would be fairly modest.

I examined several recent studies of the effects of wind energy on system reliability. Each location will be somewhat idiosyncratic, but the studies all concluded that, with wind penetration levels of 10% or even more, reliability effects are small and can be readily addressed.

The New York State Energy Research and Development Authority (NYSERDA) sponsored one such study assuming that 10% of peak load generation was provided by wind turbines (3300 MW).[16] The study (p. 2.6) found that:

- The increase in forecasting error due to wind generation for the purpose of unit commitment can be accommodated by existing processes and resources;
- The effect of wind generation on load following could be accommodated by existing processes and resources;
- No change in spinning reserve would be needed;
- The grid may meet regulation criteria with existing regulating capability;
- State of the art wind generators reduce post-fault voltage dips.

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[16] GE Energy, *The Effects of Integrating Wind Power on Transmission System Planning, Reliability, and Operations, Report on Phase 2: System Performance Evaluation*, prepared for the New York State Energy Research and Development Authority, March 4, 2005.

The NYSERDA study concluded that "it is expected that the [New York State Bulk Power System] can reliably accommodate at least 10% penetration, 3,300 MW, of wind generation with only minor adjustments to its existing planning, operation, and reliability practices... [assuming that] wind farms would include state-of-the-art technology, with reactive power, voltage regulation, and [low voltage ride through] capabilities..." (p. 2.16).

The National Renewable Energy Laboratory reviewed several studies of the effect of wind energy on the costs of reliably operating power systems (i.e., costs of unit commitment, load following so as to have adequate reserve capacity available to ramp units up and down to follow load shapes with wind plants on line, and regulation to maintain control within standards).[17] Wind penetrations varied from under 1% to 20% or more of peak load. Costs of regulation, load following, and unit commitment combined ranged from $1.47 per MWh to $5.50 per MWh.

In a Colorado study, the cost of integrating wind generation into the Public Service Company of Colorado system (regulation, load following, unit commitment and scheduling, and gas supply system impacts), was $3.51 per MWh when wind penetration is 10% and $4.77 per MWh when wind penetration is 15%.[18]

Based on these detailed modeling analyses, I conclude that the costs of integrating moderate amounts of wind energy, so as to operate a reliable system, are small. I included these integration costs in my analysis shown in Exhibit DB-2.

Q. Please compare the methods used in the studies cited above with APS' method for estimating wind integration costs.

A. In evaluating projects submitted in response to its 2005 request for proposals for renewable energy, APS assumed that it would incur costs for spinning reserves equivalent to 25% of the MW of wind generation capacity in order to maintain sufficient levels of system reliability. (APS responses to data requests WRA 4-2 and WRA 5-1). In his letter to Commissioner Mayes dated July 19, 2006, Mr. Davis stated that APS' cost of spinning reserves for wind integration is between $10 per MWh and $20 per MWh.[19] These costs are well above those determined from detailed analyses of the effects of intermittent wind resources on regulation, load

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17 J.C. Smith et al., "Wind Power Impacts on Electric Power System Operating Costs: Summary and Perspective on Work to Date," National Renewable Energy Laboratory, NREL/CP-500-35946, March 2004.

18 EnerNex Corporation, *Wind Integration Study for Public Service Company of Colorado*, report to Xcel Energy, Knoxville, TN, 2006, Table 4.

19 Letter from Jack Davis, President, APS, to Commissioner Kristin K. Mayes, dated July 19, 2006 re: Calculation of Above Market Cost for Wind Energy. The letter was docketed in Docket Nos. E-01345-05-0816 and RE-00000C-05-0030.

following, unit commitment, and other operational factors in other jurisdictions where the penetration of wind energy was assumed to be as high as 20% of peak load. The difference in wind integration costs may be due to differences in APS' assumptions about the amount of spinning reserve needed to maintain a reliable system and other studies' modeling conclusions about the amount of additional spinning reserve needed (e.g., in the NYSERDA study cited above, no additional spinning reserve was needed). I recommend that, going forward, APS should either base its integration costs on detailed modeling studies of other utilities or conduct a similar detailed modeling analysis of its own system.

Q. Does wind generation comprise a significant percentage of generation in other states?

A. Yes. Exhibit DB-5 shows wind generation capacity as a percentage of total generating capacity in states with at least 100 MW of wind generating capacity. Wind generation capacity accounts for over 6% of total generating capacity in three states (New Mexico, Minnesota, and Iowa).

Q. Are there any environmental benefits of your proposed additions to APS' portfolio of renewable resources?

A. Yes, air emissions would be reduced. Assuming that 90% of the renewable energy displaces natural gas generation and 10% displaces coal-fired generation, and assuming the July 28, 2006 price for tradable carbon dioxide emission allowances in the European Union (a mandatory market involving 10,000 large industrial and power generation establishments), the avoided carbon dioxide emissions would be valued at $12.7 million per year. At the price of carbon dioxide credits at the Chicago Climate Exchange (a much smaller voluntary market with only a few dozen members) on the same date, the avoided carbon dioxide emissions would be valued at $2.7 million per year. Also, the value of avoided sulfur dioxide emissions priced at the August 2006 futures price on the Chicago Climate Exchange on July 28, 2006 would be about $0.24 million per year. Thus, the renewable energy has an additional benefit, relative to the displaced conventional generation, of several million dollars per year over and above the value of the renewable energy as a hedge against high fossil fuel prices.

Demand Side Management to Reduce Urban Heat Island Effects

Q. What is the urban heat island effect?

A. Urban areas typically exhibit higher temperatures than comparable rural areas because of the large amounts of pavement and buildings which absorb heat. In a hot climate, like that of Phoenix, the higher temperatures lead to increased use of air conditioning and require increased generation of electricity from intermediate and peaking power plants. Phoenix has become hotter over time.[20]

Figure 1 of APS' report, *APS Investigation into Rate Designs Conducive to Conservation and DSM*, dated November 2005, and included in David Rumolo's testimony, as Attachment DJR_9, pertains to APS' hourly demand on the system peak day of 2004. Among other things, the heat island effect causes demand for electricity to remain high after sunset as seen in the Figure.

Q. How can APS reduce the urban heat island effect and thereby reduce loads during peak hours?

A. I recommend that APS pursue a demand side management program that encompasses:

- Shade from trees or other vegetation and shade structures – including commercial and residential area street trees, trees in urban parks, and parking lot trees. Vegetation also promotes cooling through evapotranspiration.
- Cool building surfaces which reflect more heat than commonly used surfaces; cool surfaces include green roofs that have vegetation on them.
- Cool pavements which reflect more heat than commonly used pavement.

Exhibit DB-6 shows an estimate of energy savings from heat island reduction measures in the Phoenix area for several building types.

Q. How should an urban heat island reduction program be incorporated into APS' demand side management activities?

A. APS already has residential and non-residential demand side management (DSM) programs that focus on individual buildings. These programs can reduce the effects of urban heat islands, but they are limited in what they can accomplish because participants are scattered around APS' service territory. In areas of new construction, builders and contractors could apply cool roofs, cool pavements, and shading to all or nearly all the new development. But such a program, if it were carried out, would not affect existing development. Therefore, it is desirable to also concentrate cool roofs, cool pavements, and shading in one or more existing, densely built-up neighborhoods.

I recommend that the Commission direct APS to include an urban heat island reduction program in APS' DSM portfolio. APS should use the existing DSM collaborative process to refine the program concept, identify the products and services

[20] L. Baker, L. Brazel, N. Selover, C. Martin, N. McIntyre, F. Steiner, A. Nelson, and L. Musacchio, "Urbanization and Warming of Phoenix (Arizona, USA): Impacts, Feedbacks, and Mitigation," *Urban Ecosystems*, vol., 6 (2002): 183-203.

to be provided (e.g., incentives, financial assistance, education, training, etc.), identify target markets (e.g., municipalities), and develop a budget and implementation schedule. To assist the collaborative, APS should initially conduct a brainstorming session for APS, collaborative members, and urban planners and landscape architects who could advise the collaborative. Funds should be included in the budget to invite outside experts to assist the collaborative. The resulting heat island reduction program plan should then be submitted to the Commission for pre-approval in a manner similar to that required of other APS DSM programs.

Environmental Improvement Charge (EIC)

Q. Does electric power production and delivery affect the environment?

A. Yes. Power generation and transmission have a variety of effects on air quality, water quality, water withdrawals, views, wildlife, etc. For example, during 2005, APS' air emissions from generation included:[21]

- 2,109 tons of carbon monoxide
- 18.3 million tons of carbon dioxide
- 34,383 tons of nitrogen oxides
- 16,801 tons of sulfur dioxide
- 2,241 tons of particulate matter (PM10)
- 0.247 tons of lead
- 0.36 tons of mercury.

Q. Please describe APS' proposed Environmental Improvement Charge.

A. APS proposes an EIC to overcome regulatory lag in recovery of substantial costs associated with environmental expenditures (Fox, p. 9, DeLizio, p. 3). The costs to be recovered through the EIC are investment and expenses associated with installation and maintenance of the environmental upgrades at APS' generation facilities (DeLizio, pp. 3-4). The proposed tariff (Schedule EIC, Attachment GAD-1) indicates that costs would be associated with environmental improvements implemented on or after January 1, 2004 for which costs have not been fully recovered, ongoing environmental improvement projects, or prospective environmental improvement projects designed to comply with environmental standards required by federal, state, tribal, or local laws or regulations, including water, waste, and air standards. The air standards include limits for SO_2, NOx, particulate matter, volatile organic compounds, and mercury.

[21] Pinnacle West Capital Corporation, *2005 Corporate Responsibility Report*. Figures pertain to APS ownership of generation.

In response to data request WRA 1-11, APS indicated that it may use the EIC for cost recovery for voluntarily reducing pollution associated with power production. APS stated that:

> *"the process for government environmental mandates often takes many years even after the science is understood to require emission reductions and the technology is available to achieve them. Where emission reductions or activities are needed to protect the environment and public health, we anticipate recovery through the EIC, including those costs necessary for complying with existing laws and anticipated future requirements. We believe this proactive approach is in the best interests of our customers and Arizona."*

Costs to be entered into the EIC account are return on capital, depreciation, operation and maintenance expenses, property taxes, and associated income taxes (DeLizio, p. 4 and Schedule EIC). At the time of a rate case, unrecovered costs could be put into base rates and the EIC would be reduced commensurately (DeLizio, pp. 6-7).

The initial costs to be recovered are those for the Cholla power plant (Fox, Attachment EZF-1): bag houses, low NOx burners, and scrubbers for the three units owned by APS. Projects would be carried out between 2004 and 2009 at a capital cost of $134.9 million (plus O&M costs). The initial charge would be $0.000152 per kWh, although APS indicated that the charge might be revised because capital costs were revised to about $160 million (response to Staff data request MJR 3-5).

The EIC rate would be applied to all retail kWh sold with a few exceptions set forth in Schedule EIC. APS would file annual requests for updates and true-ups of the EIC by March 15. Staff would review the proposals and the Commission would have to act by June 15 of each year or else the new EIC rate goes into effect automatically (DeLizio, p. 5, Attachment GAD-2), subject to a subsequent true-up. Over or under collections would accrue interest at a rate equal to APS' pre-tax cost of capital (DeLizio, p. 6, Attachment GAD-2, APS response to data request WRA 1-15).

Q. What environmental improvements does APS expect from the proposed controls at the Cholla plant?

A. APS expects reductions in sulfur dioxide emissions at Units 1 and 3, reductions in nitrogen oxide emissions at all three units, reductions in particulate emissions at Unit 1, and reductions in mercury emissions at Units 1 and 3 (APS response to data request WRA 1-8). Sulfur dioxide emissions cause respiratory illness, create haze, and react with other substances in the air to form acids which damage plants, soils, lakes and streams, and damage buildings and monuments. Nitrogen oxides contribute to the formation of ground level ozone in the presence of sunlight and this ozone in turn causes respiratory illnesses. Nitrogen oxides also contribute to acid rain similar to sulfur dioxide, form nitric acid which causes respiratory illnesses, affect water quality in coastal estuaries, contribute to eutrophication of water bodies, impair visibility, and cause biological mutations. Particulate emissions affect respiratory health, reduce visibility, and damage buildings and monuments. Mercury, in the form of methylmercury, impairs neurological development in humans and can cause death, reduced fertility, slower growth, and abnormal behavior in wildlife. Elemental mercury, when breathed as a vapor, causes numerous toxic effects.

Q. Has the Commission authorized charges similar to the EIC?

A. Yes. The Commission authorized a DSM charge for APS in Decision No. 67744 (Settlement Agreement paragraph 43) and authorized a surcharge for the Environmental Portfolio Standard. The Commission is also considering a surcharge for the proposed Renewable Energy Standard.

Q. Does WRA support APS' proposed EIC?

A. In general, WRA supports the concept of the EIC for several reasons:

- Some resource choices have greater environmental impacts than others and the EIC makes the attributes of those choices more apparent to APS, the Commission, and ratepayers. The costs of the Cholla improvements add about $1 per MWH to the costs of operating the Cholla plant.[22]
- Utilities should not be discouraged from complying with environmental regulations or pursuing beneficial environmental goals through fear of disallowances for doing the right thing.
- Utilities should be encouraged to take actions that reduce environmental damages caused by power generation, including compliance with regulations, actions taken in anticipation of future regulation, or societally beneficial responses to environmental issues for which no regulation is imminent.
- The EIC reduces the risk to APS of complying with environmental regulations by increasing the likelihood of timely cost recovery.

Q. Do you recommend any changes to the EIC as proposed by APS?

A. Yes. APS should be able to recover the costs of voluntarily reducing emissions beyond those mandated by government regulation, upon Commission approval of specific projects. Reduced pollution improves human health and reduces the impacts of power generation on the environment. Additionally, voluntarily reducing

[22] Calculated by dividing the revenue adjustment for the test year due to the EIC (Schedule H-1) by the kWh produced by Cholla Units 1-3 in 2005 as reported in APS' FERC Form 1: $4,315,000/4,608,054 MWh.

environmental impacts is becoming a part of normal business activity. For example, leading electric utilities and other energy companies have voluntarily acted to reduce their emissions of carbon dioxide.[23] Therefore, Schedule EIC should be modified to include voluntary environmental improvements.

Q. What costs should be excluded from recovery through the EIC?

A. I recommend that the Commission not allow recovery of penalties assessed for non-compliance with environmental regulations. APS has indicated that it does not expect to recover such fines through the EIC (response to data request WRA1-9).

Climate Change and the EIC

Q. Should environmental improvements include reductions of greenhouse gas emissions?

A. Yes. Increased concentrations of greenhouse gases in the atmosphere are contributing to global climate change. Scientific evidence on human-caused climate change is persuasive:[24]

- "Greenhouse gases are accumulating in Earth's atmosphere as a result of human activities, causing surface air temperatures and subsurface ocean temperatures to rise."
- "The surface warming trends are solidly grounded in observational science and consistent with human-induced pressures."
- "There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities."
- "The scientific consensus is clearly expressed in the reports of the Intergovernmental Panel on Climate Change (IPCC). … [T]he evidence for human modification of climate is compelling. … This analysis shows that scientists publishing in the peer-reviewed literature agree with IPCC, the National Academy of Sciences, and the public statements of their professional societies. Politicians, economists, journalists, and others may have the

[23] For example, Cinergy (Ceres, *Electric Power Climate Risk Disclosure*, 2005); American Electric Power and Entergy (Innovest Strategic Value Advisors, Carbon Disclosure Project, *Carbon Finance and the Global Equity Markets,* 2003).

[24] Sources for the following quotes are: Committee on the Science of Climate Change, National Research Council, "Climate Change Science: An Analysis of Some Key Questions," National Academy Press, 2001, p. 1. Stephen H. Schneider, presentation to the U.S. Senate Committee on Commerce, Science and Transportation Hearing on 'The Case for Climate Change Action,', October 1, 2003, p. 2. Intergovernmental Panel on Climate Change (IPCC), *Climate Change 2001, Synthesis Report*, Summary for Policymakers, p. 5. Naomi Oreskes, "The Scientific Consensus on Climate Change," *Science*, December 3, 2004, vol., 306, number 5702, p. 1686.

impression of confusion, disagreement, or discord among climate scientists, but that impression is incorrect."

Greenhouse gases consist of carbon dioxide, methane, nitrous oxide, and several industrial chemicals. Carbon dioxide is the most important anthropogenic source of increased greenhouse gas concentrations.

Impacts of increased concentrations of greenhouse gases in the atmosphere include increases in temperature, rising sea levels, changes in precipitation patterns, and more extreme weather phenomena (e.g., drought, floods).[25] As a result, food and water resources, ecosystems, biodiversity, human settlements, and human health will all be affected at enormous cost. Components of climate change may occur abruptly or gradually. In sum, reductions in greenhouse gas emissions would constitute an environmental improvement.

Q. Will APS face costs of reducing greenhouse gas emissions?

A. Yes. In general, it is prudent to expect that APS will incur costs to either comply with future state or federal greenhouse gas emission regulations or voluntarily pursue corporate policies to reduce its greenhouse gas emissions. Proposals and policies at the federal and state level to reduce greenhouse gas emissions include, for example:

- Proposed federal legislation, such as: the McCain-Lieberman Climate Stewardship Act of 2003 (S. 139) and the McCain-Lieberman Climate Stewardship and Innovation Act of 2005 (S. 1151) which would cap emissions of carbon dioxide; and multi-pollutant bills such as S. 556 (2002) and S. 150 (109th Congress) which would set a cap on carbon dioxide emissions from electric power generators.
- The Regional Greenhouse Gas Initiative (RGGI) among Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont which is intended to stabilize carbon dioxide emissions from the region's power plants at current levels from 2009 to the start of 2015 followed by a 10% reduction in emissions by 2019.
- The Governor of New Mexico's Executive Order 05-033, *Climate Change and Greenhouse Gas Reduction*, which set targets for reducing greenhouse gas emissions to year 2000 levels by 2012, 10% below 2000 levels by 2020, and 75% below 2000 levels by 2050. APS obtains electricity from coal-fired power plants located in New Mexico.
- Arizona Climate Change Advisory Group, *Climate Change Action Plan*, draft, July 2006.

[25] Intergovernmental Panel on Climate Change (IPCC), Climate Change 2001. In particular, see the volumes subtitled, *Summary for Policymakers*, and *The Scientific Basis*. Hadley Centre, "Stabilising Climate to Avoid Dangerous Climate Change," 2005.

APS may, in the future, propose to include recovery of the costs of greenhouse gas emission reduction activities in the EIC or in base rates.

Q. What is APS' possible cost exposure?

A. APS is currently seeking new base load power supplies. Selection of resources which emit large amounts of carbon dioxide will expose APS and its ratepayers to significant cost risk over a long time period. A new pulverized coal plant would emit about 1850 pounds of carbon dioxide per MWh generated. Based on recent activity in greenhouse gas markets, offsetting such emission levels might cost between $5 per metric ton and $30 per metric ton.[26] Thus, APS would face costs between about $0.0042 per kWh and about $0.025 per kWh in addition to fuel costs, operating and maintenance costs, depreciation, and return on investment. Adding a new 400 MW pulverized coal plant with an 85% capacity factor to APS' generation portfolio exposes APS to annual costs of about $12.5 million to $75 million. Coal plants may place long term burdens on ratepayers.

Q. Would APS be at risk for other costs associated with greenhouse gas regulation?

A. Yes. If APS completes installation of a new pulverized coal plant in, for example, 2012, that plant would normally recover depreciation and return on investment for at least 30 years, i.e., through 2042. However, if the effects of climate change are found to be abrupt and dangerous in the next 10 to 20 years, the federal government or state governments may act quickly and decisively to reduce carbon dioxide emissions. As a result, APS may be required to shut down coal-fired power plants, thereby stranding some of its investment.

Q. What are APS' carbon dioxide emissions?

A. Exhibit DB-7 shows APS' historical and forecast carbon dioxide emissions. APS is reducing its carbon dioxide emissions intensity (pounds per MWh) through around

[26] There are several markets for greenhouse gas emission reduction credits. The European Union Allowance market covers about 10,000 large industrial and power generating sources. The Chicago Climate Exchange is a voluntary market with about 41 members. Members commit to an emissions reduction target and if they do not meet the target they must acquire allowances or project-based offsets. There are also international markets in Certified Emission Reductions, Verified Emission Reductions, and Emission Reduction Units. Most of the projects generating these reductions are located in Asia and consist of hydrofluorcarbon destruction projects, landfill gas projects and coal mine methane projects. As of August 2, 2006, the price of European Union Allowances was about $21 per metric ton of carbon dioxide and the price of vintage 2006 carbon financial instruments on the Chicago Climate Exchange was $4.40 per metric ton.

2010, but total emissions are increasing. If APS acquires more conventional coal generation in the future, both emissions and emissions intensity are likely to increase.

Q. What actions are states taking to reduce greenhouse gas emissions from power generation?

A. The RGGI mentioned above is a salient example. As a second example, the California Public Utilities Commission is investigating the adoption of a greenhouse gas emissions performance standard that is no higher than the greenhouse gas emission levels of a combined cycle natural gas turbine.[27] As a third example, the Oregon Energy Facility Siting Council set a carbon dioxide emission performance standard for natural gas baseload plants and all non-baseload plants at 0.675 pounds of carbon dioxide per kWh, which is lower than what can be obtained from such plants, requiring offsets or other actions to meet the standard.[28]

Q. What actions are utilities and other companies taking to manage greenhouse gas risks?

A. The following elements are important in developing, analyzing, and implementing greenhouse gas emission risk management strategies:

- Assignment of responsibilities for greenhouse gas emission management to specific utility managers and to the board of directors.
- Provision of incentives for utility managers to responsibly and effectively manage greenhouse gas emissions.
- Preparation of an inventory and historical time line of greenhouse gas emissions from power generation, transportation, transmission, and other utility activities.
- Incorporation of a variety of public input into the development and analysis of greenhouse gas risk strategies.
- Analysis of greenhouse gas emission risks by such means as including a range of adders for emission compliance costs for each resource option to be considered in long range plans.
- Consideration of non-traditional coal options which significantly reduce carbon dioxide emissions into the atmosphere such as integrated gasification combined cycle (IGCC) technology with carbon capture and sequestration.

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[27] California Public Utilities Commission, Policy Statement on Greenhouse Gas Performance Standards, October 6, 2005. Such a policy would preclude significant importation of electricity generated by conventional coal-fired power plants without carbon capture and sequestration.

[28] www.oregon.gov/energy/siting/docs/ccnewst.pdf

- Consideration of off-site greenhouse gas emission reduction strategies such as purchasing tradable verifiable emission reduction credits, offsets, and long term verifiable sequestration of carbon dioxide in forests or soil, for example.
- Reduction of greenhouse gas emissions through energy efficiency, greater use of renewable energy, increased power plant efficiency, and other means.
- Commitments to greenhouse gas emission reduction targets.
- Regular public reporting of greenhouse gas emissions and management activities.

Q. Has APS undertaken actions to manage greenhouse gas emissions?

A. APS has taken some actions. It set a corporate target for 2010 of reducing carbon intensity (pounds of carbon dioxide emissions per MWh) by 10% relative to year 2000 ("Excellence 2010: Owning the Challenge"), estimated historical and projected carbon dioxide emissions, and estimated sulphur hexafluoride emissions. Further, APS has announced a pilot program to produce natural gas from coal using hydrogasification (press release July 5, 2006). In response to WRA data request WRA 1-24, asking APS to describe how greenhouse gas emissions are incorporated in investment and resource decisions made by APS' and Pinnacle West's senior managers and board of directors, APS stated:

> "When considering resource options APS includes the cost of compliance with existing legislation and considers the potential for evolving environmental policy."

No further details were provided.

Q. What actions do you recommend that the Commission take at this time to foster prudent climate change policies for APS whose costs may be recovered through the EIC or base rates?

A. Broadly speaking, APS should explicitly and fully take into account greenhouse gas emission risks when making resource decisions and should actively manage the risks associated with greenhouse gas emissions. With regard to the current rate case, I recommend that the Commission direct APS to complete the following tasks:

Task 1. **Management Plan**. Prepare, with public input, a greenhouse gas emissions management plan that: a) updates its inventory of greenhouse gas emissions, historical trends in greenhouse gas emissions and forecasts of greenhouse gas emissions, b) identifies senior managers responsible for greenhouse gas emission analyses and risk management, c) analyzes the financial and cost risks APS faces as a result of greenhouse gas emissions, d) identifies and analyzes risk management strategies, and e) outlines how APS will incorporate the preceding elements into its resource planning and selection activities going forward. This management plan should be submitted to the Commission no later than 18 months after the Commission's decision in this case.

Task 2. **Carbon Emission Reduction Study**. Conduct, with public input and with the assistance of outside expertise, an analysis of the applicability of coal technologies with significantly reduced carbon dioxide emissions, including, but not limited to, IGCC with carbon capture and sequestration, and the hydrogasification technology APS plans to pursue on a pilot basis. The analysis should address the current status of and expected future progress in carbon dioxide emission reduction and carbon capture and sequestration options, including costs of technologies reviewed. The study should also address the extent to which traditional utility regulation should be modified to encourage adoption of carbon dioxide emission reduction technologies and carbon capture and sequestration technologies. This analysis should be completed within 12 months of the Commission's decision in this case and should be used in Task 1. APS and participating members of the public should regularly review the work of the outside experts and provide input into the study.

Task 3. **Commitment and Action Plan**. Prepare, with public input, a long term greenhouse gas commitment and an associated action plan for Commission review and approval. The long term commitment and action plan should address at a minimum: emissions covered, enforceability, incentives, benchmarks, targets and associated schedules, duration of the commitment, methods of implementation, estimated costs, cost recovery through the EIC or by other means, measurements of implementation progress, and conditions under which targets may be revised. The commitment and action plan should be submitted to the Commission at the same time as the management plan set forth in Task 1.

Q. What type of Commission review of the management plan, carbon emission reduction study, commitment, and action plan do you recommend?

A. The Commission should review and either approve, approve with modifications, or disapprove the management plan, carbon emission reduction study, and company commitment and action plan. This review should combine all three tasks into one review and may be accomplished at an open meeting or hearing. If the Commission disapproves the management plan, carbon emission reduction study, or commitment and action plan, it should provide direction on how to proceed with climate change risk management and associated cost recovery.

Q. What should the Commission do if APS acquires or commits to acquire additional supply side resources prior to Commission approval of APS' climate change plans, analyses, and commitments?

A. Because acquisition of new fossil fuel resources will lock in long term emissions of more greenhouse gases, I recommend a three step process. First, APS should fully evaluate the potential costs of complying with greenhouse gas emission requirements or similar requirements that may be imposed by government for each resource that it considers. The January 2006 request for proposals (RFP) for base load resources speaks very generally about considering environmental impacts of resource options. APS should request more environmental information on bids before making a final selection under this RFP, including information on bidders' willingness to bear the cost of complying with future greenhouse gas regulations or to acquire offsets of carbon dioxide emissions. Second, no more than 30 days after committing to any new resources, APS should file with the Commission its evaluation of its potential cost exposure associated with future greenhouse gas emission requirements, its analysis of the resource options considered, and the reasons for selecting the winning resources. This filing may include confidential information. Third, at the time APS requests recovery of the costs of complying with any greenhouse gas emission requirements applicable to those resources or costs of voluntary emission reduction goals, the Commission should consider the prudence of APS' selection of the resources by reviewing APS' evaluation of the potential compliance costs at the time it evaluated its resource options and selected specific resources.

There is precedent for such a policy. In Decision No. 65347 (dated November 1, 2002), the Commission ordered that, as a condition of constructing Springerville Unit 4, the developers of Springerville Units 3 and 4, and not Tucson Electric Power Company ratepayers, should bear any risk of the costs of possible regulation of carbon dioxide emissions in the future (Finding of Fact 45).

Q. What are your recommendations concerning the public input proposed above?

A. APS would be responsible for conducting the tasks, submitting the reports, and adopting a company commitment to greenhouse gas reductions. A collaborative consisting of interested parties to this case should be established by the Commission at the time of the Commission's decision in this case. The collaborative would meet regularly with APS, provide advice to APS and its consultants, and review APS' drafts and proposals for carrying out the work inherent in each Task. I recommend that the same collaborative members be involved in all three Tasks. The input provided by the collaborative would be similar to that provided by the DSM collaborative which was established in Decision No. 67744. Participation in the collaborative does not imply that a party accepts APS' plans, analyses, or commitments, but it does reduce the likelihood of serious disagreements and misunderstandings and it provides APS with a wider range of input than it might otherwise obtain.

Q. If the Commission rejects the EIC, would your recommendations on the climate change plans, studies, and commitments presented above remain the same?

A. Yes.

Summary of Recommendations

Q. Please summarize WRA's recommendations.

A. With regard to APS' green power tariff:

- The Commission should approve a green power tariff but the tariff should be modified from APS' proposal as described below.
- Charges for green power should exclude the RES charge and the Environmental Improvement Charge.
- The premium for green power, which is added to the otherwise applicable rate, should be calculated as the cost per kWh of green power minus the base power supply cost, minus the power supply adjustor, and minus an allowance for capacity credits associated with the green power.
- APS should not offer green power until it has adequate renewable energy to serve green power customers, provided that the start date for green power service should be no later than one year after the Commission's decision in this case.
- The minimum block size for green power (in the kWh option) should be 100 kWh per month.
- APS should select a set of low cost, stably priced renewable energy resources to serve green power customers.
- Within six months of the Commission's decision in this case, APS should propose to the Commission a green power premium based on the specific resources it selects and should propose revising the tariff from time to time as cost elements change.
- APS should seek Green–e certification for its green power product.
- APS should submit annual green power reports covering renewable energy acquired by technology, customer enrollment by class, kWh green power sales, green power revenues, and green power costs. These reports could be submitted as part of APS' RES reports.
- If the green power tariff becomes oversubscribed relative to the amount of green power resources, APS should put new applicants on a waiting list until it has acquired sufficient green power resources. Costs of energy from green power resources in excess of green power sales could be used to meet RES requirements or could be recovered in APS' purchased power costs.

With regard to using renewable energy as a hedge against high natural gas prices:

- The Commission should direct APS to acquire 1,300 GWH per year of low cost, stably priced renewable energy under long term contracts starting within the period from 2008 through 2010 and continuing for at least 15 years. This renewable energy is in addition to that obtained in compliance with Decision No. 67744.

- APS should file for Commission review, within 4 months of the date of the Commission's decision in this case, a renewable energy acquisition plan that incorporates input from interested parties obtained via a collaborative process.
- APS should file reports with the Commission by March 1 of 2009, 2010, and 2011 describing its progress in meeting the goals and proposing actions to make up any deficiencies in meeting the goals. The Commission may set a course of action to deal with problems and deficiencies in meeting the goal.
- APS should recover the costs of the renewable energy either through the RES (if the resources are eligible) or through its power supply adjustor.
- APS should either base its wind integration costs on detailed modeling studies of other utilities or conduct a similar detailed modeling analysis of its own system.

With regard to demand side management to reduce urban heat island effects:

- APS should propose an urban heat island reduction program as part of its DSM portfolio. This program should be developed using input from the DSM collaborative and outside experts and should focus on geographically contiguous areas as opposed to individual buildings scattered around urban areas.

With regard to the Environmental Improvement Charge:

- The Commission should approve APS' proposed EIC and expand its scope to include, upon Commission approval of specific projects, voluntary environmental improvements.
- The Commission should not allow recovery of penalties assessed for non-compliance with environmental regulations.

With regard to climate change and the EIC:

- The Commission should direct APS to prepare, with public input obtained in a collaborative process, a climate change management plan, a carbon emission reduction study, and a climate change commitment and action plan, and deliver the plans and studies to the Commission within 18 months of the Commission's decision in this case. The Commission should review the plans and studies and approve, approve with modifications, or disapprove APS' plans. If the Commission disapproves the plans it should provide direction on how to proceed with climate change risk management and associated cost recovery.

- If APS acquires any new supply side resources before the Commission has approved a climate change management plan, related analyses, commitments, and action plans for APS, I recommend a three step process. First, APS should fully evaluate the potential costs of complying with greenhouse gas emission requirements or similar requirements that may be imposed by government for each resource that it considers. Second, no more than 30 days after committing to any new resources, APS should file with the Commission its evaluation of its potential cost exposure associated with future greenhouse gas emission requirements, its analysis of the of resource options considered, and the reasons for selecting the winning resources. This filing may include confidential information. Third, at the time APS requests recovery of the costs of complying with any greenhouse gas emission requirements applicable to those resources or costs of voluntary emission reduction goals, the Commission should consider the prudence of APS' selection of the resources by reviewing APS' evaluation of the potential compliance costs at the time it evaluated its resource options and selected specific resources.

Q. Does this conclude your direct testimony?

A. Yes.

Qualifications of David Berry

Education:

B.A.	Syracuse University (Geography)
M.A. & Ph. D.	University of Pennsylvania (Regional Science)

Employment History:

- Western Resource Advocates, Senior Policy Advisor (2001 - present)
- Navigant Consulting, Inc., Senior Engagement Manager (1997-2001)
- Arizona Corporation Commission, Chief Economist and Chief, Economics and Research (1985 – 1996)
- Boston University, Department of Urban Affairs and Planning, Lecturer (1981-1985)
- Abt Associates, Inc., Senior Analyst (1979-1985)
- University of Illinois, Department of Urban and Regional Planning, Visiting Assistant Professor (1977-1979)
- University of Pennsylvania, Regional Science Department, Lecturer (1974 –1977)
- Regional Science Research Institute, Research Associate (1972-1977)
- US Army (1969-1971)

Testimony and Public Comment:

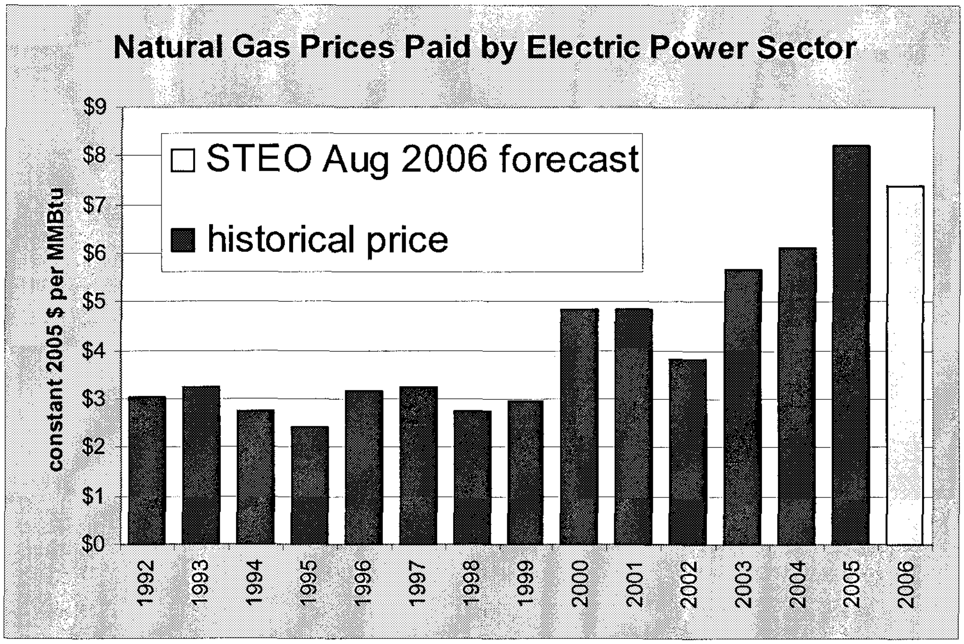
- Before the Maine Land Use Regulation Commission
- Before the Arizona Corporation Commission
- Before the New Mexico Public Regulation Commission
- Before the Public Utilities Commission of Nevada

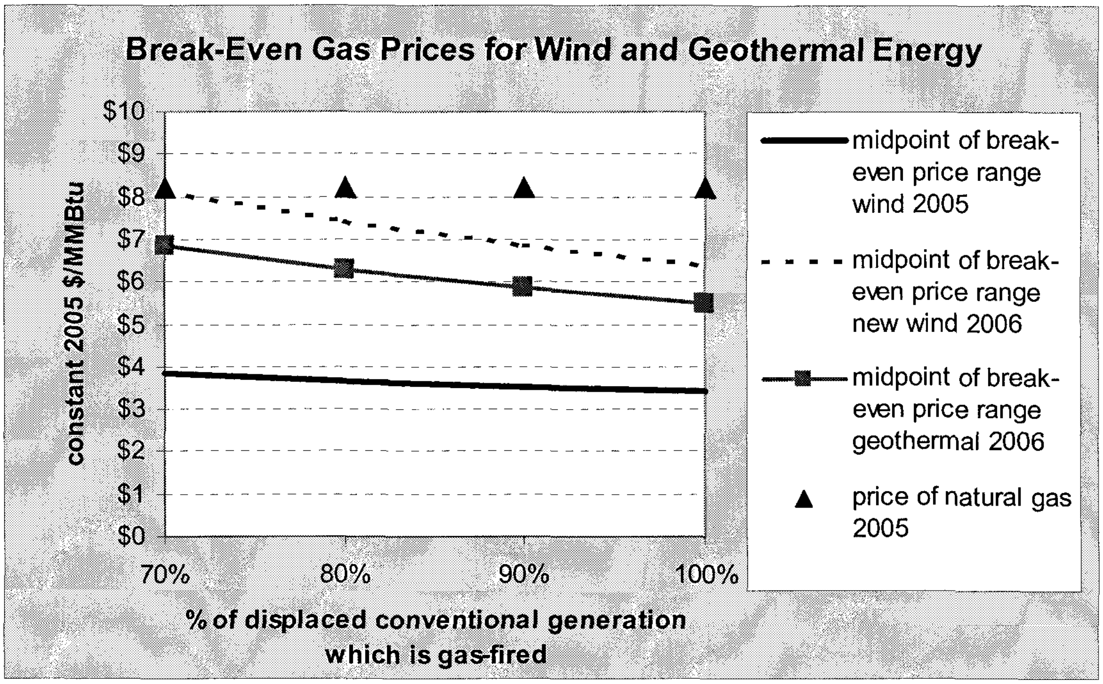
Articles in:

- *Ecological Economics*
- *Energy Policy*
- *Journal of the American Planning Association*
- *Local Environment*
- *Solar Today*
- *NRRI Quarterly Bulletin*
- *The Electricity Journal*
- *Journal of Economic Issues*
- *Public Utilities Fortnightly*
- *Journal of Environmental Management*
- *Business Economics*
- *American Journal of Economics and Sociology*
- *Water Spectrum*
- *Geographical Perspectives*
- *Strategic Planning for Energy and the Environment*
- *National Tax Journal*
- *Policy Sciences*
- *Natural Resources Journal*
- *Water International*
- *Growth and Change*
- *Home Energy*
- *Professional Geographer*
- *Public Management*
- Chapters in books and proceedings

Service on Boards and Advisory Groups

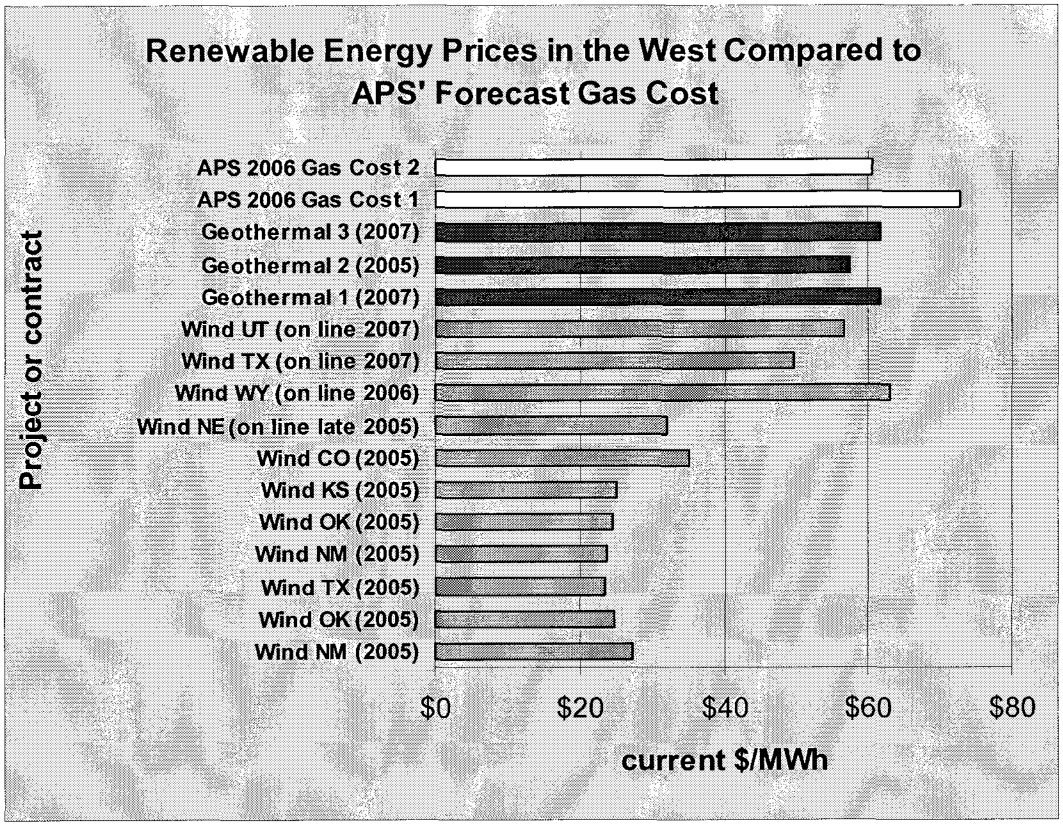
- Scottsdale Library Advisory Board (2003-2005)
- Governor's Energy Efficiency and Renewable Energy Working Group (2004-2005)
- Arizona Comparative Environmental Risk Project (1993-1995)





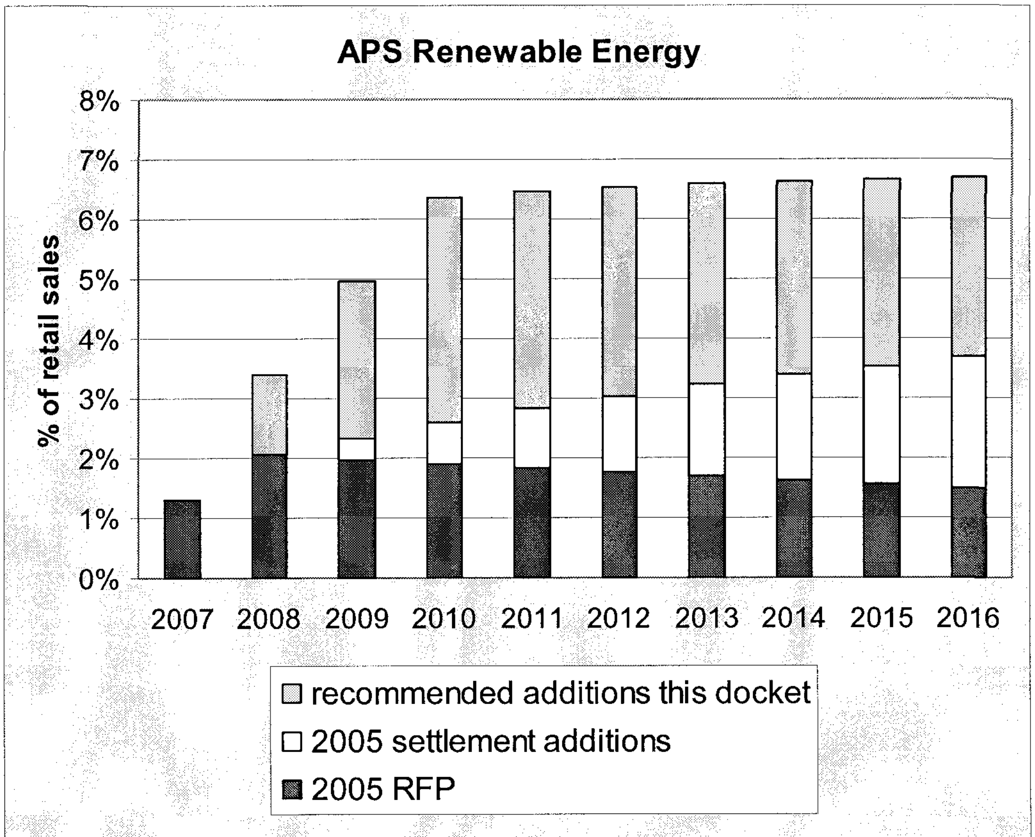
The break-even prices are the natural gas prices at which the cost of renewable energy equals the avoided energy and capacity costs of natural gas-fired generation. The cost of wind energy includes wind integration costs. When the price of natural gas paid by the electric power sector is above the break-even price, renewable energy costs less. In recent years, gas prices have been sufficiently high that many wind energy resources and some geothermal resources are cheaper alternatives. Future natural gas prices are uncertain, so it is appropriate to regard renewable energy resources as hedges against high gas prices in the future. The hedge value of renewable resources is enhanced when utilities purchase renewable energy at a fixed or stable price that is not tied to the price of natural gas. See testimony narrative for assumptions used to prepare the chart.

EXHIBIT DB-3



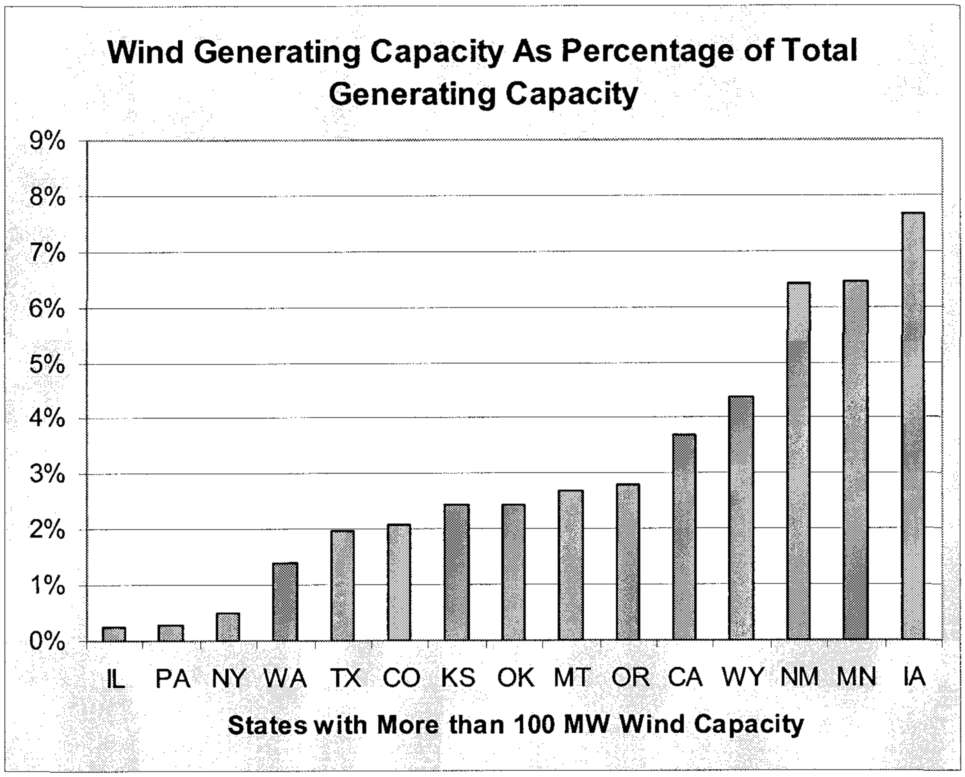
Prices are:

- Wind energy prices paid in 2005 for projects in various western states
- Wind energy prices for new projects starting operations in late 2005 or later
- Geothermal contracts (Salton Sea area) starting in 2005 or later
- APS average cost of natural gas fuel expense for APS' own load for 2006: includes gas transportation cost and subtracts gas hedge from fuel cost.
    - APS 2006 Gas Cost 1 is calculated from Peter Ewen's workpapers PME_WP3, pages 1, 3
    - APS 2006 Gas Cost 2 is calculated from APS' revised cost projections provided in its response to data request LCG 2-1



Explanation of Graph

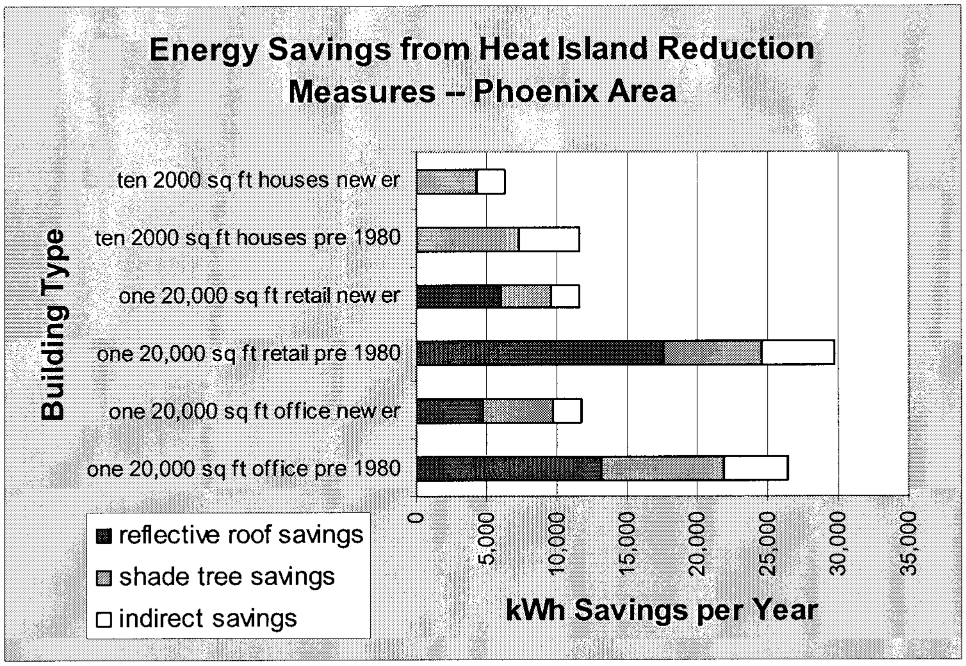
1. Retail sales are assumed to grow at historical rate (1980-2005). Transmission and distribution losses from renewable energy generation are assumed to be 5% of generation.
2. ***2005 RFP*** assumes APS will obtain all the energy expected under the biogas, geothermal, and wind contracts resulting from the 2005 RFP process (Decision Nos. 67744 and 68296 as modified in APS data response WRA1-18). Percentage declines over time because energy amount is constant and retail sales grow.
3. ***2005 settlement additions*** pertain to renewable energy corresponding to 10% of capacity additions per the previous settlement agreement (Decision No. 67744), APS' response to WRA data request WRA 2-1 and APS' response to Staff data request EAA 4-16. Effect of additions is cumulative over time.
4. ***Recommended additions*** pertain to renewable energy acquisitions that would be obtained if WRA's recommendations in this docket were adopted by the Commission. Additional renewable resources are assumed to be phased in over three years. Then the percentage in the graph declines over time because energy amount is constant and retail sales grow.



Data Sources

Wind generating capacity from American Wind Energy Association, "Wind Energy Projects throughout the United States of America," as of December 31, 2005.

Total generating capacity from Energy Information Administration, *Electric Power Annual* database for 2004 (most recent data available). Capacity refers to summer capacity (MW) and includes coal, dual fired, hydro, natural gas, nuclear, other gas, other renewables, petroleum, pumped storage, and other capacity for electric utilities, independent power producers, and combined heat and power.



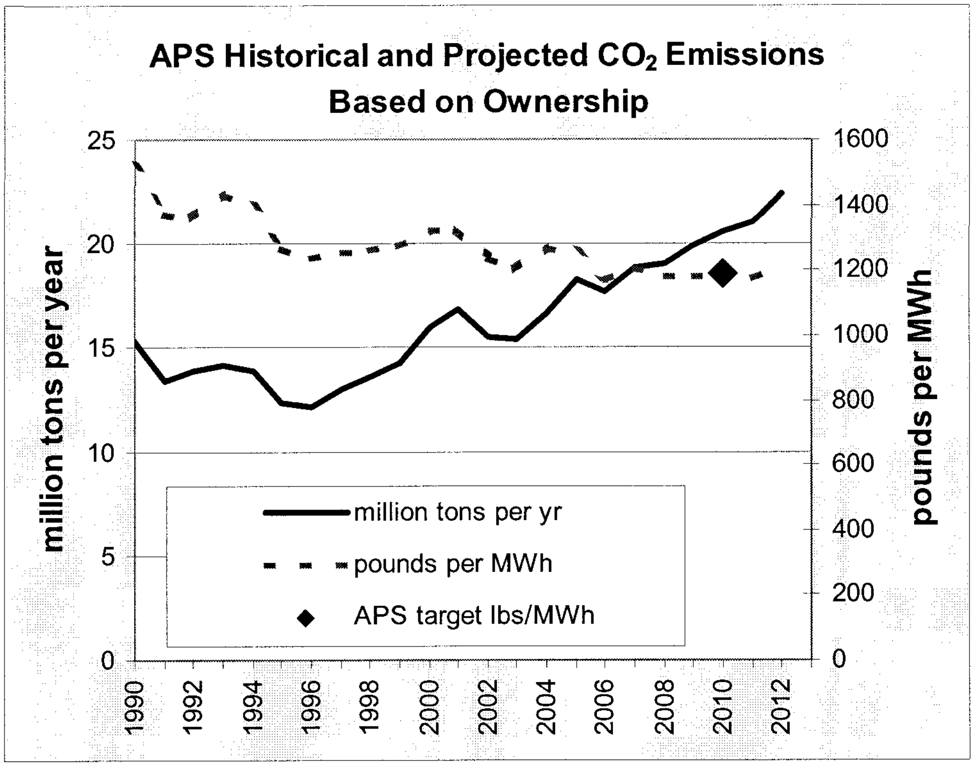
Source: H. Akbari and S. Konopacki, "Calculating energy-saving potentials of heat-island reduction strategies," *Energy Policy* 33 (2005): 721-756.

Assumptions for DSM measures are as follows:

- Solar reflective roofs are commercially available for office buildings and retail stores, but are not widely available for residential applications with sloping roofs. Therefore, savings for reflective roofs for residential applications are not shown.
- Shade trees are placed on south and west walls near windows: 4 trees per house, 8 trees per office, and 10 trees per retail store.
- Indirect savings represent impact of street and other urban trees and reflective building surfaces and pavements.

Buildings are classified by vintage because newer buildings tend to be more energy efficient.

Buildings assume electric heat. Savings for gas heated buildings are very similar.



Source: APS' responses to WRA data requests 3-2, 3-3, and 3-4.